

Fracture Detection, Mapping, and Analysis of Naturally Fractured Gas Reservoirs Using Seismic Technology

**Heloise B. Lynn, lynninc@compuserve.com
K. Michele Simon,
Wallace Beckham**

**Lynn Incorporated
1646 Fall Valley Dr.,
Houston, TX 77077
USA**

Introduction

This paper describes work done in three projects funded by the U.S. Department of Energy (DE-AC21-92MC28135, DE-AC21-94MC31224, and DE-AC21-93MC30086) as part of its ongoing research effort aimed to expand current levels of drilling and production efficiency of naturally fractured tight gas reservoirs. The Department of Energy has identified the tight gas sands of the Rocky Mountain basins as a tremendous resource reserve. It is necessary, however, to drill in the naturally fractured areas in order to obtain commercial wells. The demonstration of seismic detection (prediction) of high fracture density capable of generating commercial gas production is the goal of our work. The two active study areas are in a Wind River Basin, Wyoming, USA, naturally fractured gas reservoir, and in the Rulison Field, Piceance Basin, CO. The completed study area was at Bluebell-Altamont, UT, in a naturally fractured gas reservoir in the Upper Green River formation.

Objectives

The goal of the project is to demonstrate using field seismic data the direct seismic detection of high fracture density and estimation of fracture azimuth using P-wave reflection seismic data, with support from shear-wave reflection and VSP (vertical seismic profile) data. Vertical aligned gas-filled fractures affect seismic waves as additional ordered compliant members. Additional ordered compliant members cause *azimuthal anisotropy*, a condition which affects seismic waves in a measurable fashion. The P-waves are affected when their propagation path (the source-receiver azimuth) is perpendicular to the vertical aligned fractures. The shear waves are most affected when their polarization (particle motion direction) is perpendicular to the aligned vertical fractures. Shear waves are the

slower traveling body wave, compared to the P (or compressional) body wave. A shear wave has particle motion orthogonal to ray, or propagation, direction, while the P-wave has particle motion parallel to ray direction.

Azimuthal anisotropy is evident in P-wave data when one source-receiver raypath direction senses more compliant rocks, while the orthogonal direction senses less compliant rocks. The velocities and amplitudes of the reflected P-waves depend upon: 1) the azimuth of the source-receiver and 2) the offset (distance) between source and receiver (or angle of propagation off-vertical).

Approach

From previous published work, it has been established that the greater the magnitude of the fracture density, the greater the magnitude of the shear wave seismic anisotropy (Crampin, 1985). Lynn et al, 1996, showed in the Bluebell-Altamont, UT, study that the P-wave data were also sensitive to the fracture density, such that the difference of the P-wave AVO (amplitude variation with offset) gradient by azimuth was proportional to the shear wave anisotropy. This 2-D evaluation of seismic anisotropy using nine-component (9C) reflection seismic and 9C VSP field data, has been extended to 3-D, P-wave reflection evaluation, supplemented with 3-D converted wave and 9C VSP field data in the current active projects. "Component" refers to the type of seismic body wave under study: vertical component, or one component, indicates P-wave, or compressional wave, the standard seismic wave used in oil and gas exploration and production reflection surveys. "Multi-component" refers to the additional dimensions of investigation needed to record and/or produce the shear waves, the second body wave, which travels at about half the velocity of the P-wave. Shear waves are more sensitive to fracture orientation and fracture density, but are more difficult and costly to use in acquisition, processing, and interpretation. P-waves are easier to use in acquisition, and processing, but can offer some interpretation ambiguity due to heterogeneity between the two raypaths compared in interpretation. Our task is to collect, process, and interpret a 3D P-wave field data set in a manner that will capture, preserve, and highlight the internal evidence of azimuthal anisotropy.

Acquisition

We recommend azimuthally isotropic arrays of sources and receivers, which could be point sources or areal source arrays, and circular geophone arrays or point receivers. There is a fringe of low-fold, non-usable data around the edges of 3D shoots: the acreage which needs to be evaluated should be positioned within the full-fold, full-offset, full-azimuth migration-aperture coverage area. We recommend a square patch of live receivers centered on the source point, with maximum offset in all azimuths equal to target depth plus about 10 or 20 %, which is a standard AVO design criteria. At least several square miles of

data are collected in this manner, in order to evaluate the azimuthal variation of velocity and amplitude for each reflecting point (bin) in the subsurface.

All geologic data pertaining to the existence and orientation of natural fractures, and the in-situ stress field, as well as any evidence of preferred direction of flow, should be used in the interpretation phase of the project (Lynn et al., 1995).

Processing

Pre-processing steps include geometry description (location of sources and receivers), surface-consistent amplitude correction and surface-consistent deconvolution. By sorting over azimuth (first) and offset (second) in a super-gather, the azimuthal variation of velocity may be determined. We used eighteen 10 degree-gathers, to scan from 0 degrees (North) to 180 degrees (South). Alternatively, a scan from 0° to 360° at 20-degrees increments could be done. We found that the azimuthal velocity variations are in general aligned with the amplitude variations over azimuth. Figure 1 shows the azimuth and offset distribution (horizontal and vertical axes respectively) in a supergather (Location 2) from the Wind River Basin study. Each small square symbol is an input trace; the traces within each large square were summed to form one output trace in the supergather display. Supergather displays are shown in Figures 2 through 6. In Figure 2, a 1980 by 1980 ft square supergather at Location 2, the variation in velocity by azimuth is clearly seen by the changes in the far offset's traveltimes after a single velocity function was applied at all azimuths. The velocity applied appears to correctly flatten the package of reflections arriving at 1.30 to 1.50 seconds (near the top of the fractured-gas interval) at 80 degrees source-receiver (S-R) azimuth, while the other source-receiver azimuths show these reflections dipping towards the right. These dipping reflectors indicate that more time to the far offset was recorded in the NS azimuths. More traveltimes indicates that a slower velocity is present NS, as compared to EW; this is consistent with the EW vertical aligned fractures known to exist in the Wind River Basin project area. In this case, the 80 degree S-R azimuth is thus established as the fast azimuth.

Another observation on Figure 2 is that the reflection traveltimes on the near to mid-range offsets at 80 to 100 degrees S-R is less than the reflection traveltimes on the near to mid-range offsets at 170 to 10 degrees S-R azimuth. This is best observed on the reflection arriving at 2.02 seconds at 90 degrees S-R azimuth; at 10 degrees S-R, the reflection arrives at 2.03 seconds. A 10-millisecond traveltimes difference is well within the limits of resolution of modern seismic analysis, and implies another method for identifying the fast and slow S-R azimuths from an azimuthal supergather scan. If the 80 to 100 degree S-R azimuth data were correctly moved out and stacked, and the 170 to 10 degree S-R data were also correctly moved out and stacked, then the stacked reflections in the E-W azimuths (80-100 degrees) should arrive at shorter traveltimes than the stacked reflections in the N-S (170 to 10 degrees) S-R azimuths. Thus, the faster velocity azimuth would have

the minimum traveltimes, which is intuitively expected. However, we have not observed this expected azimuthal variation in reflection traveltimes in the stacked data. We did observe that the “fast velocity” direction, which is parallel to the effectively open fractures, usually has the greater stacked traveltimes, while the “slow velocity” direction usually has the minimum stacked traveltimes. We explain this field data observation by noting that on velocity scans, the typical effect of increasing the stacking velocity is to flatten the moveout hyperbola which moves the T0 (time zero, or zero offset intercept) deeper in time. Also, decreasing the stacking velocity steepens the moveout hyperbola which moves the T0 shallower in time. Therefore, the effect of azimuthal variations in stacking velocity can be to cause counter-intuitive differences in the stacked data traveltimes.

In scanning for velocity and amplitude variation by azimuth, we recommended examining different areal sizes of supergathers, because inherent in this type of analysis is a trade-off between higher fold to improve the signal-to-noise ratio, and loss of precision due to smearing over geologic heterogeneities. Figure 3 shows a supergather centered at the same location as that shown in Figure 2, but reduced to a 990 ft by 990 ft square area. Although the fold is reduced from taking only one-fourth of the data used in Figure 2, the main conclusion, that the fast S-R azimuth is at 80 degrees for the 1.30-1.50-second reflections, is still visible on this display.

Figures 4 and 5 show a 1980 by 1980 ft square and a 990 by 990 ft square supergather, centered at the same point (“Location 4”). In these displays the reflections at 1.30-1.50 seconds appear correctly moved-out at 70 to 100 degrees S-R, and under-corrected for other S-R azimuths. Again, as in Figures 2 and 3, the fast direction is nearly E-W and the slow direction, nearly N-S. The reflections at 2.45 - 2.60 seconds (below the base of the fractured reservoir section under study) show the same azimuthal velocity variation as the shallower reflection events, but interval velocity calculations are needed to determine the direction of azimuthal anisotropy within a section of interest. In addition to velocity variation by azimuth, the amplitudes of the main reflecting packages also show azimuthal variation (the amplitudes in the E-W azimuths appear weaker than the amplitudes in the N-S azimuths), with implications for P-wave seismic identification of high-fracture density zones using amplitude characteristics. The observations of a dominant EW fast direction for the supergathers in the Wind River Basin P-wave survey allows the entire survey to be separated by S-R azimuth, EW from NS.

Once the two principal directions (fast and slow) are determined, the data volume is divided into these two source-receiver azimuths, and individual velocity analyses proceed. Velocity scans located every 1/4 mile or finer are recommended, plus velscans at all wells of interest. Velocity control at wells aids in evaluating the relationship between EUR and seismic attributes. Pre-stack time migration is an option; alternatively, the near and far halves of the live fold may be stacked, and then migrated, in order for subsequent AVO (two point, far minus near) analysis. The "Fractogram" analysis, which Western

Geophysical is developing, offers a more powerful and more automated approach than the one listed above, in that four or more azimuths are processed and analyzed using computer-automated procedures. The Fractogram approach, when complete, is scheduled to be available for use on field data.

A benefit of a four-azimuth approach is that cracks striking at 45 degrees to the two principal azimuths may be diagnostically sensed. If a small area of the survey contains cracks at 45 degrees to the dominant trend, the two-azimuth approach is expected to sense these cracks equally on both azimuths; thus no anisotropy is measured, but an intermediate slow velocity in both directions would be measured, indicating no anisotropy. The four-azimuth approach offers the ability to measure any vertical fracture orientation, and to estimate the magnitude of the fracture density. If the aligned fractures are not vertical, but consistently dipping in one direction (say, north), then we would examine the data to compare the north-to-south raypaths with the south-to-north raypaths.

Interpretation

Interpretation begins with the standard mapping of reflectors throughout the survey area, for both azimuths. Horizon amplitude maps and horizon dominant frequency maps may then be constructed, and compared for azimuthal differences. If an AVO gradient volume exists, then it can be evaluated for the AVO gradient associated with each reflector of interest. After time structure maps for horizons of interest are constructed, then the 3D stacking velocity cubes are sliced at the horizon time and the stacking velocity extracted for the horizons of interest. From these maps, the Dix interval velocity for intervals of interest can be calculated, and thus the azimuthal variation of interval velocity may be calculated for every bin. We use a ratio to express the relationship of the azimuthal variation in velocity:

$$(\text{interval velocity slow direction}) / (\text{interval velocity fast direction}),$$

where the “slow” and “fast” directions are those previously identified from azimuthal scans of supergathers.

If there are wells within the 3D survey area, their estimated ultimate recovery from the zone(s) of interest needs to be calculated, in order to compare to the various seismic attributes. The seismic attributes of interest are:

interval velocity by azimuth, interval velocity ratio (slow/fast), AVO gradient by azimuth, AVO gradient difference by azimuth (slow-fast), interval frequency by azimuth, difference in interval frequency, and others as suggested by the data. Thus, for each area, the relative usefulness of a seismic attribute to predict EUR may be evaluated. So far, for the two P-wave 3D surveys, the interval velocity ratio (slow/fast azimuth) has shown the best correlation with EUR (the greater the difference in interval velocity by azimuth, the greater the EUR). Rather than a linear relation between azimuthal ratio of interval velocity and

EUR, we have observed an interval velocity ratio threshold above which a correlation is established. We suggest that this P-wave interval velocity ratio threshold may be related to a threshold in fracture density, distinguishing between non-connected cracks and interconnected, fluid-conductive fractures, such as that documented by Crampin (1994) using shear-wave birefringence.

Sometimes, the geology of the reservoir or prospect area is best evaluated as an interval, rather than as a reflector, in that there is a large column of prospective section, and the operator would wish to drill where there is the maximum likelihood of many fractured sands. Moreover, often these non-marine sands are discontinuous and variable, so that mappable seismic reflectors only exist at the top and the base of a prospective interval. In these circumstances, a further interpretation effort is required to evaluate the azimuthal properties of an interval: average absolute reflection amplitude, average frequency, average AVO gradient within the interval, etc., and then examine the sum and the difference by azimuth of the seismic property. The difference by azimuth of a property will reveal the presence or absence of anisotropy for crack sets striking within approximately ± 20 degrees of the two azimuths along which the 3D data volume was divided. The sum of the attribute of both azimuths will reveal the potential for matrix porosity pay (isotropic) or, pay in cracks at 45 degrees to the two azimuths.

Empirical relationships between the seismic attributes and the production statistics (EUR, estimated ultimate recovery) are evaluated, and maps showing the distribution of the attributes which correlate with the EURs are generated. Figure 6 shows the correlation of four seismic attributes with EUR in the Rulison Field project. Figure 7 shows a map of “prospective” seismic attributes related to EUR for the Rulison Field project. Subsequently, only the best two attributes (velocity anisotropy and sum of AVO gradient) were used to make a map showing the areas most prospective for drilling. The higher number of points show where there are the most seismic indicators that correlate with gas production from the control set of wells in the field. In both the Wind River and Piceance Basin study areas, gas production is strongly dependent on fracture density.

Potential Pitfalls

Care must be taken that variations in acquisition, processing, or interpretation do not masquerade as azimuthal anisotropy. For example, a no-permit zone, with no sources, will cause lost coverage, which might affect the velocity determination. Processing must carefully ensure that the amplitudes are handled appropriately. In interpretation, the questions of heterogeneity (different rocks along different raypaths) versus anisotropy may arise. We anticipate that in the future, tomographic inversions of the densely-sampled stacking velocity fields will result in azimuthally comparable volumes of interval velocity.

Benefits

The use of P-waves to detect azimuthal anisotropy represents a significant cost benefit when compared to the traditional use of shear waves for this purpose. We foresee reductions in the acquisition cost of multi-azimuth P-wave surveys (as larger and larger recording-channel systems become available), since only conventional seismic sources and receivers are required. Since some shear wave data are desirable for calibration of the P-wave data, acquisition of a multi-component VSP or a small patch of converted-wave (3C) data is recommended. As successful identification of high fracture density zones can be made with 3D multi-azimuth P-wave data plus small quantities of shear wave data, this technology will have broad appeal to operators in tight gas plays in the Rocky Mountain basins, as well as other areas.

Shear wave anisotropy was recognized as the optimal technical method for identifying fracture zones, but due to the prohibitive cost of 3D shear wave acquisition, only a handful of major companies are using it, and usually within cost- and data-sharing consortia. Interest in the use of P-wave seismic to identify fracture zones dramatically increased after the publication of the D.O.E. work at Bluebell-Altamont (1994-1995): currently there are at least five major groups investigating the P-wave seismic response in naturally fractured media. These groups include:

- Western Geophysical Research: the development of "Fractogram", a processing code to investigate multi-azimuth volumes (four or more), or super gathers of 18 azimuths, for interval velocity variation by azimuth and the variation of the AVO response by azimuth (Mallick et al., 1996).
- ARCO/Gas Research Institute: the investigation of azimuthal variations in the stacking velocity of 3D multi-azimuth data (Corrigan et al., 1996).
- Intevep (Venezuela) has documented that the P-wave AVO gradient varies by azimuth in a fractured-oil reservoir, in a manner consistent with the crack orientation as determined by P-S reflection data with support from geologic data (Perez and Gibson, 1996).
- Considerable modeling and theoretical investigations have been conducted by the Colorado School of Mines (Ruger, 1996; Tsvankin, 1996).
- The Edinburgh Anisotropy Project, sponsored by the British Geological Survey, is investigating P-wave AVO differences on tielines in the North Sea (personal communication, Colin Macbeth, 1996).

- The first published field data case of P-wave azimuthally-variant AVO gradients interpreted to signify vertical aligned fractures was by W. Johnson of Coastal Oil and Gas (1995).

Conclusions

Direct detection of high fracture density zones containing vertical aligned gas-filled fractures is our attainable goal using 3D P-wave seismic data with S-wave calibration data. The fractures are the permeable conduits that affect production rates and volumes: the vertical aligned open fractures act as additional ordered compliant members which cause the azimuthal anisotropy. Azimuthal anisotropy is manifest in S-wave data as S-wave splitting (bi-refringence), and in 3D P-wave multi-azimuth data as measurable differences in velocity and amplitude characteristics, when the correct two or more azimuths are compared. The correct two azimuths to compare are those at ninety degrees (orthogonal) to each other, at which the maximum difference (by azimuth) in the velocity and amplitudes are exhibited. The applications/benefits of these techniques are lower cost seismic exploration/development tools (when compared to 3D multi-component seismic), and anticipated improvement in drilling results.

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Figure Captions

Figure 1. Azimuths and offsets sampled within a 1980 by 1980 ft square in the subsurface, at a supergather in the Wind River project. Output traces to supergather displays (large dashed squares), are 4 to 6-fold trace sums (small squares indicate input traces).

Figure 2. Wind River project Supergather 2, 1980 by 1980 ft subsurface area, showing narrow-azimuth trace gathers by azimuth (0 to 180 degrees from North). One velocity function was applied to all azimuth gathers. Azimuthal variation of moveout velocity is evident on reflections at 1.30-1.50 sec. and at 2.05 sec. Correct moveout at 80-100 degree azimuths (approximately EW) establishes EW as the "fast" direction. Reflection traveltime on near to mid-range offsets also varies with azimuth; reflection at 2.02 sec EW arrives at 2.03 sec NS.

Figure 3. Wind River project Supergather 2, 990 by 990 ft central square, produced to reduce "smearing" over changing geologic features, still shows the azimuthal velocity variation seen in Figure 2.

Figure 4. Wind River project Supergather 4, 1980 by 1980 ft subsurface area, shows similar azimuthal velocity variation as at Supergather 2. Reflections on EW azimuths require faster stacking velocities than on NS azimuths. Azimuth-dependent amplitudes are also observed.

Figure 5. Wind River project Supergather 4, 990 by 990 ft subsurface area, shows the same azimuth-dependent stacking velocities of the larger subsurface area.

Figure 6. Rulison Field project (Piceance Basin), display of seismic attributes related to well EUR for control set of 21 wells. Attributes are weighted with points according to their correlation with gas production: attribute weighting = (average EUR of wells showing attribute)/(average EUR of all wells in control set).

Figure 7. Rulison Field project (Piceance Basin), Map of seismic attributes related to well EUR. Colors are points according to weighting scheme outlined in Figure 6, as computed for all (220 by 220 ft) subsurface bins. Warm colors are interpreted to indicate a better predicted correlation with gas production. The structure map (black contours) is Top of Cameo Coals with faults picked from 3D seismic.

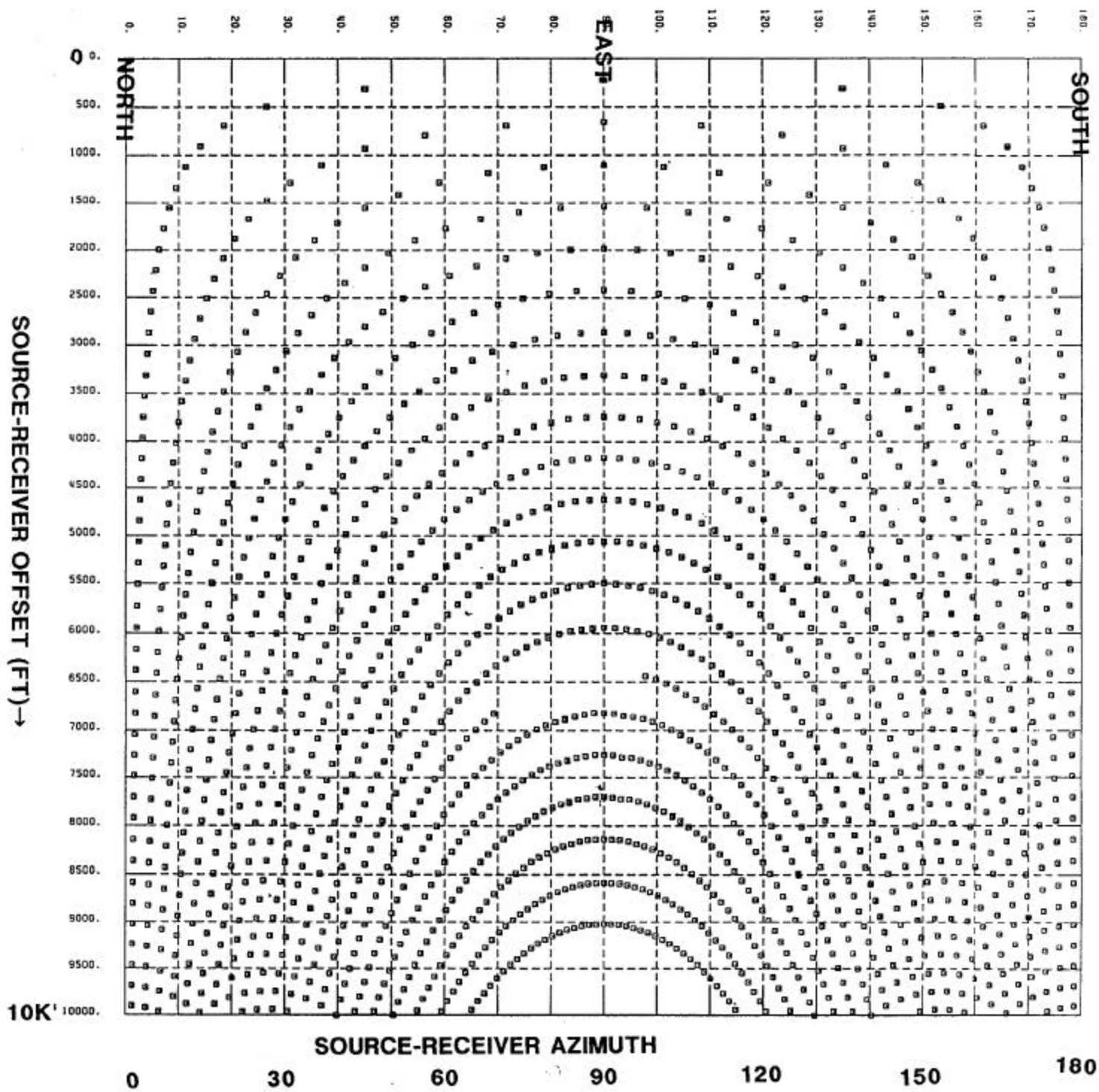
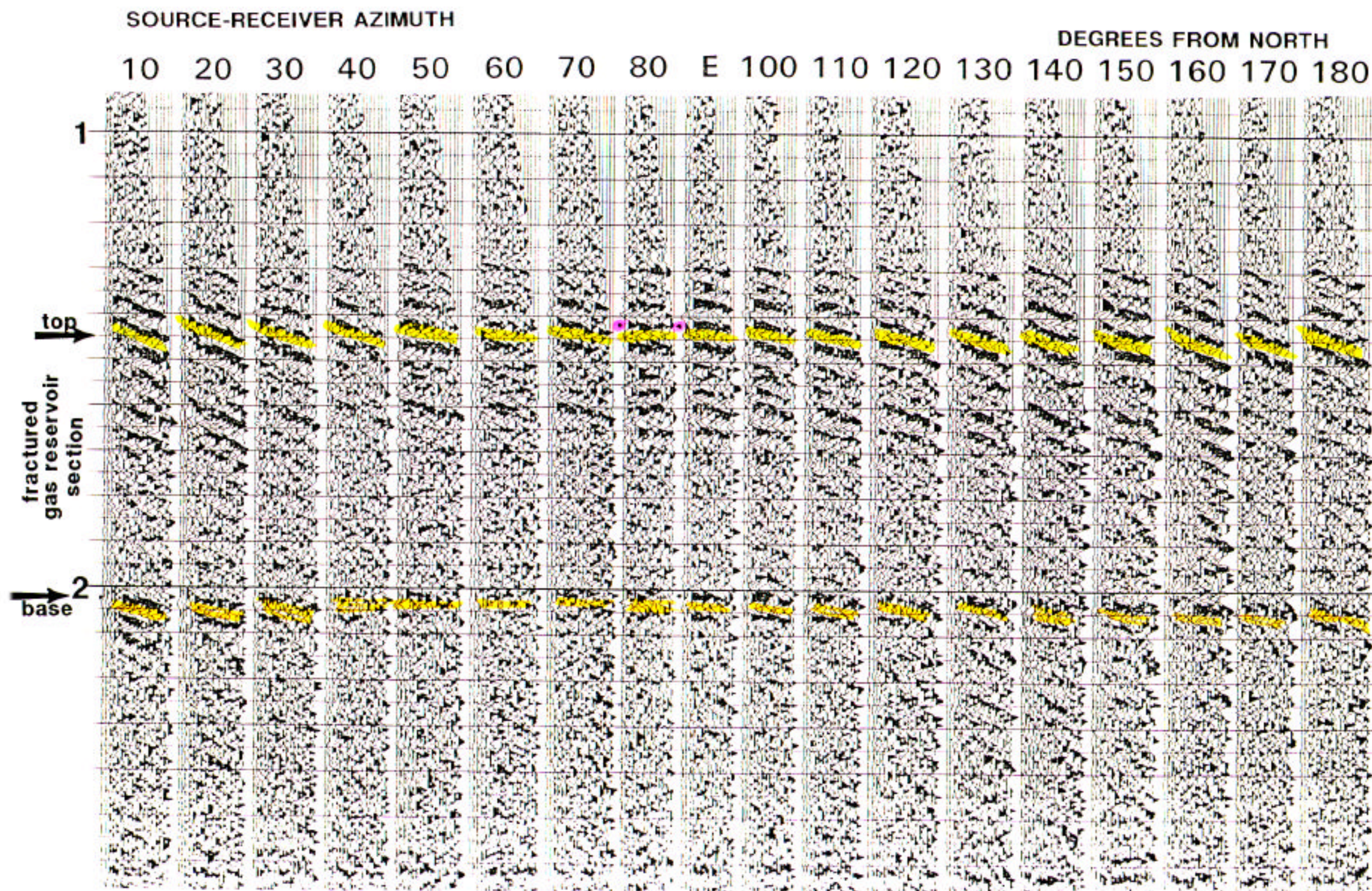


Figure 1



AZIMUTH BIN #2

1980'x1980'

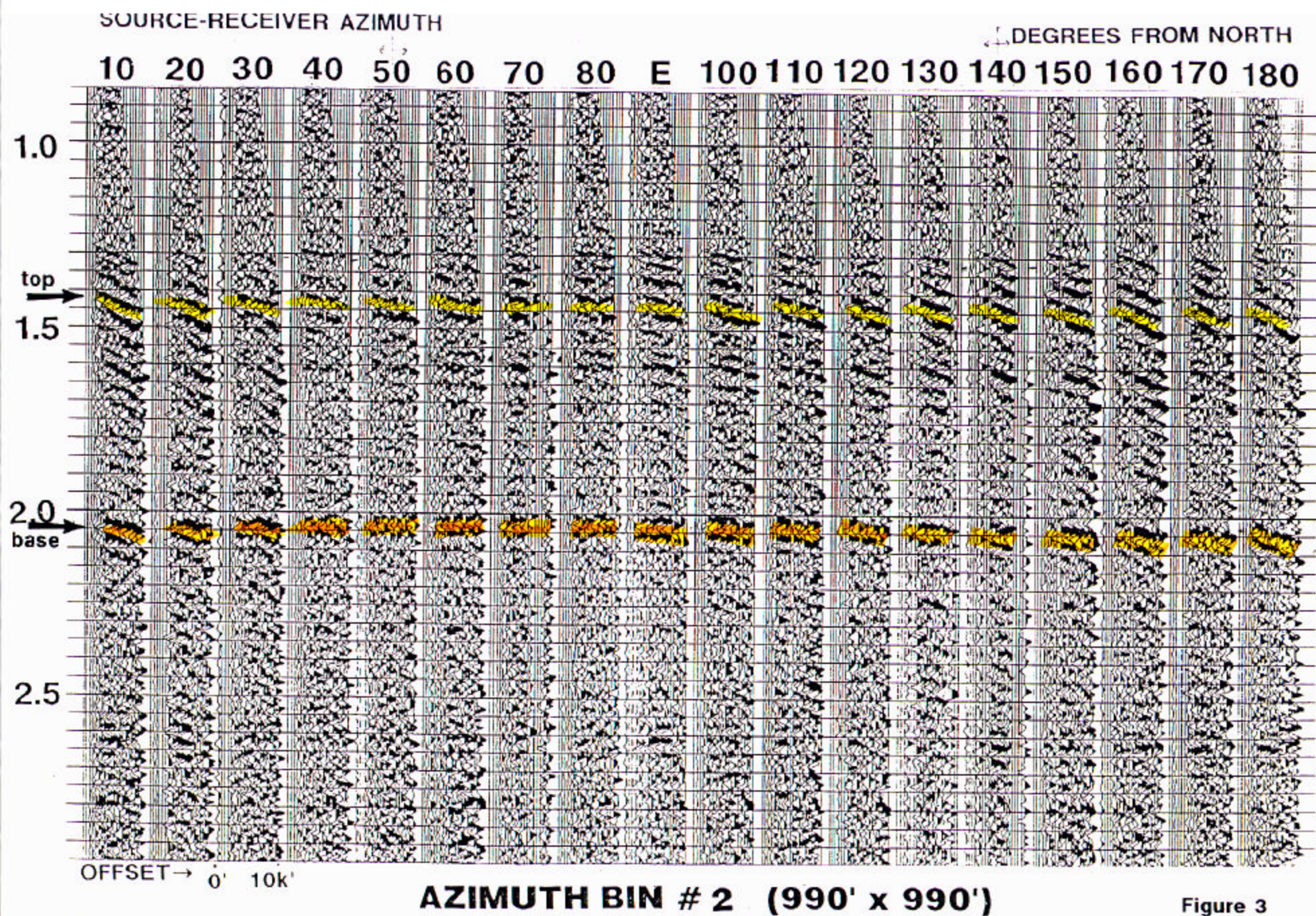
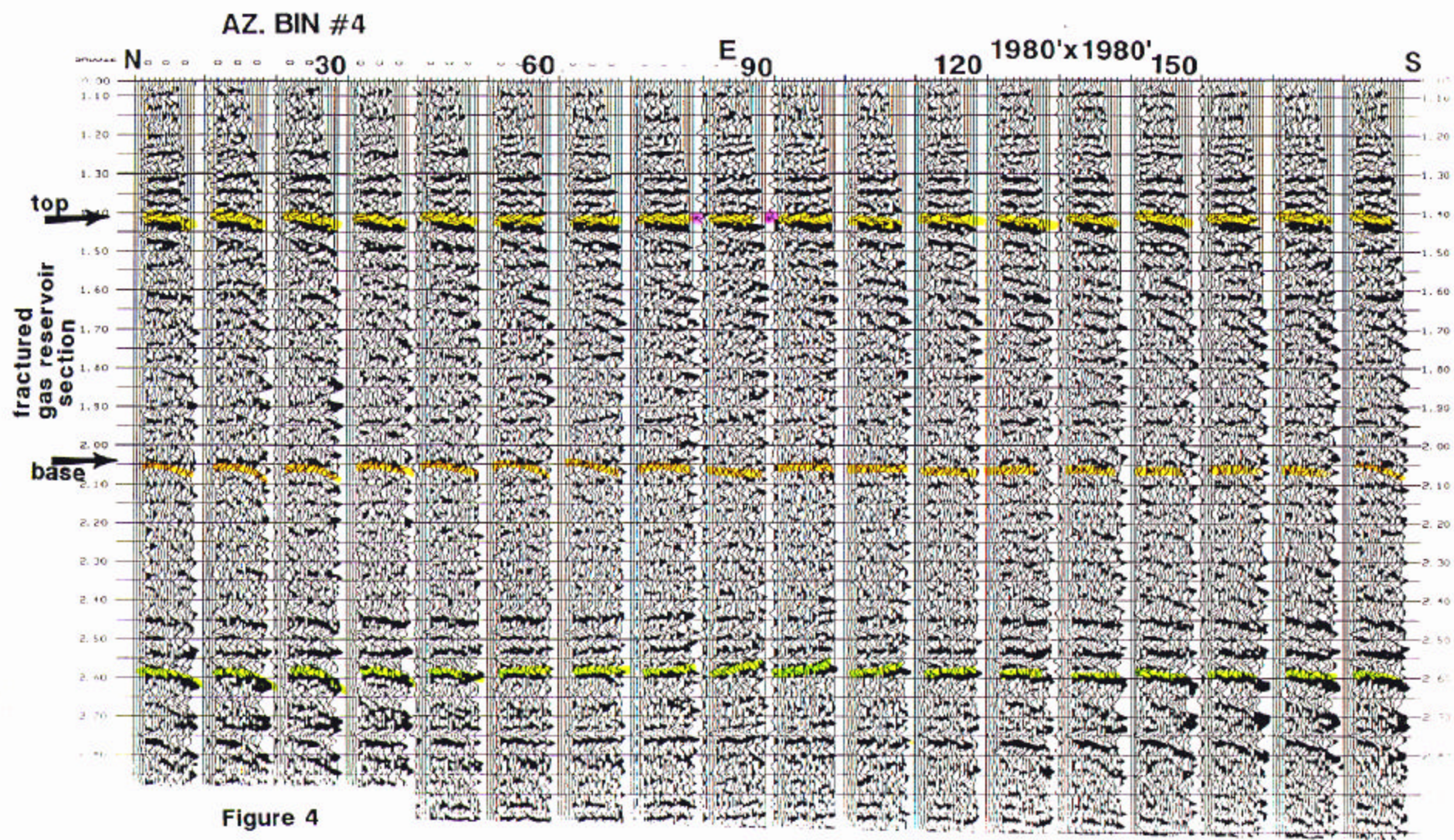
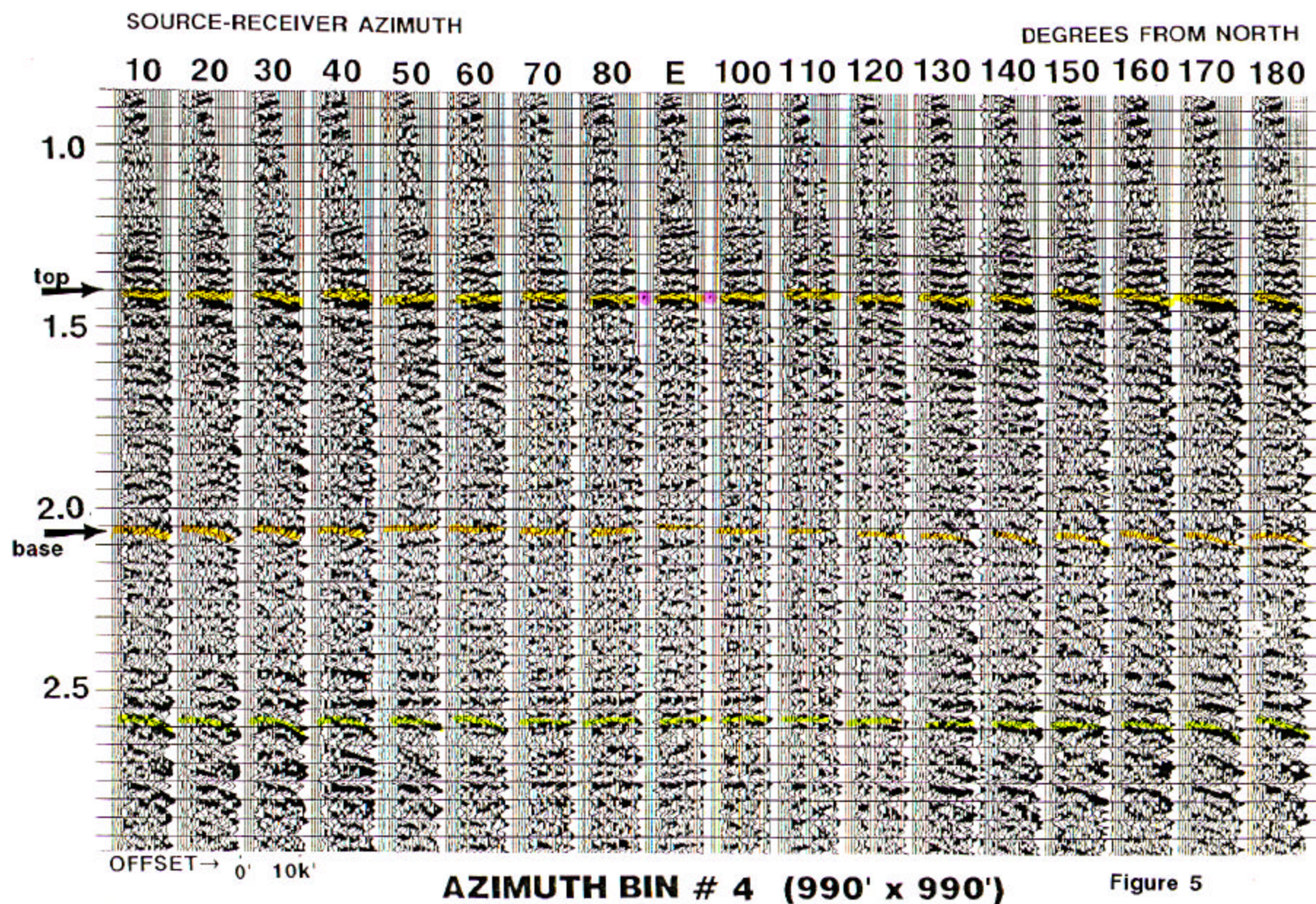
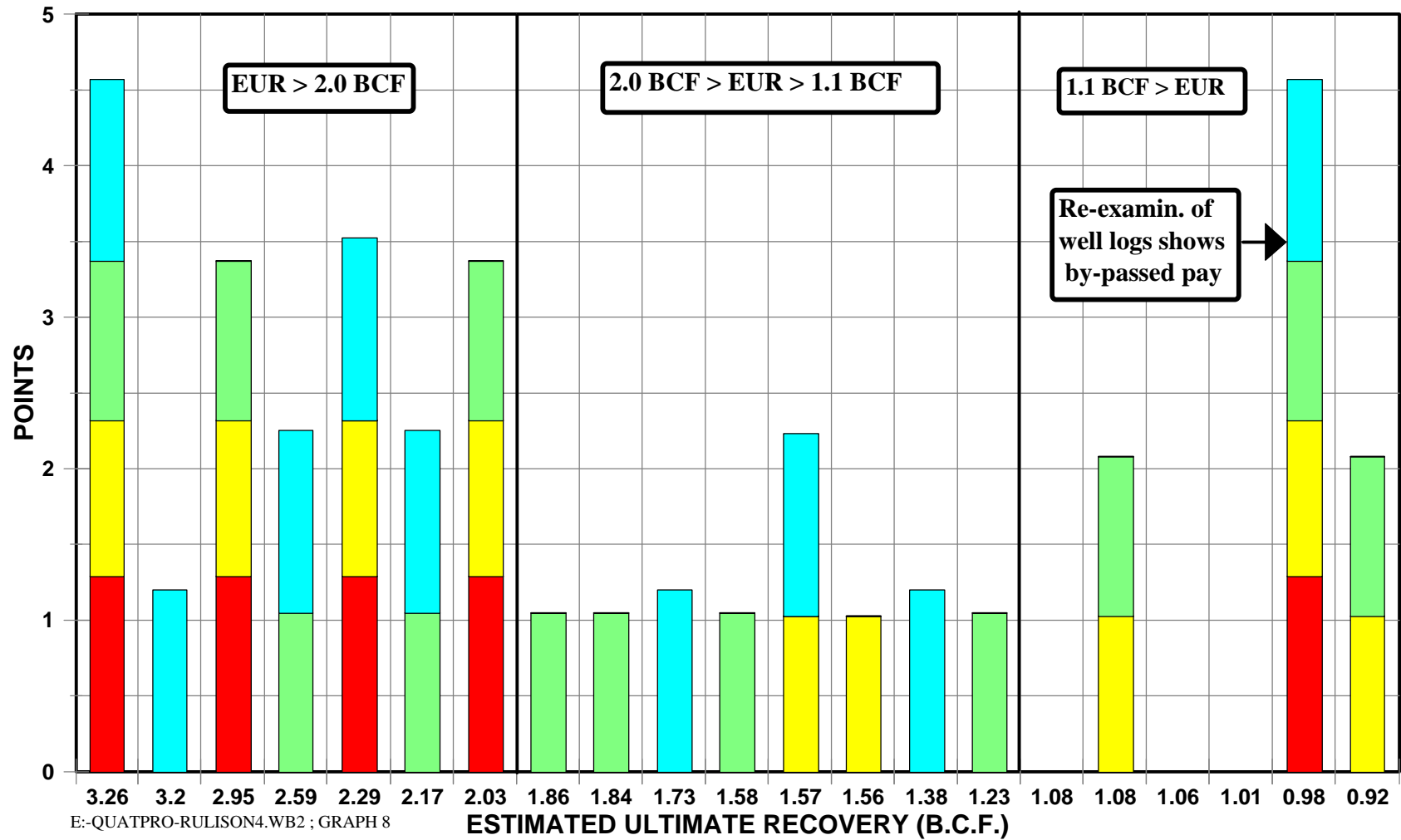


Figure 3

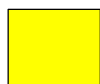




D.O.E. RULISON FIELD STUDY



VEL. ANIS., 1.29 PT IF > 4 %



MAX. INT. VEL., 1.03 PT IF >13500'/S



|DIF OF AVO GRAD|, 1.05 PT IF >100

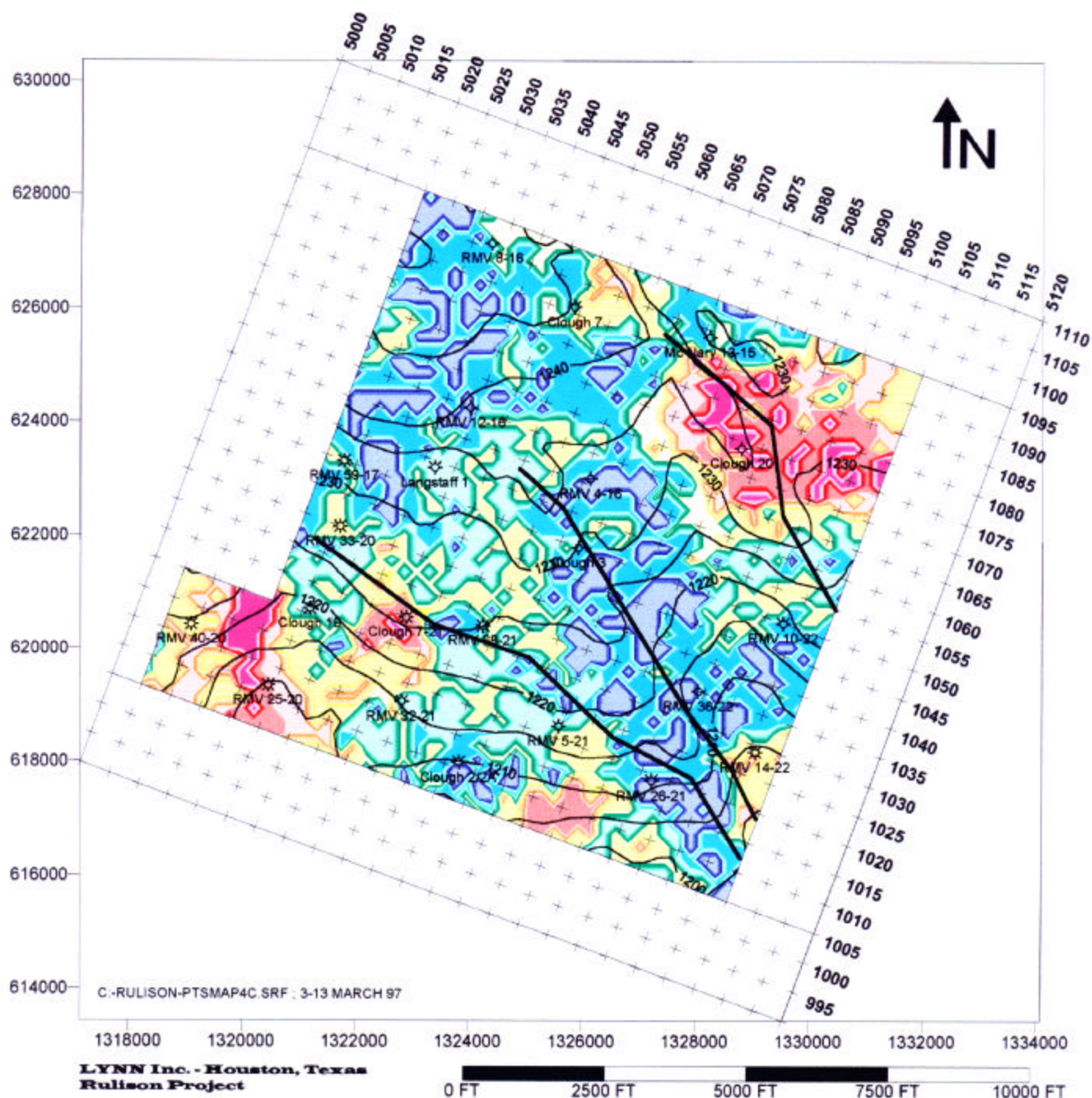


SUM OF AVO GRAD, 1.2 PT IF >250

SINGLE BIN VALUE USED FOR AVO AT WELLS

FIGURE 6

RULISON FIELD : SEISMIC ATTRIBUTES RELATED TO E.U.R.



- ☼ EUR > 2.0 BCF
- ☼ 1.0 BCF < EUR < 2.0 BCF
- ☼ EUR < 1.0 BCF

FIGURE 7